MODELING HOURLY OPERATIONS AT GLEN CANYON DAM

Colorado River Storage Project, Arizona

GCPS09 version 1.0

September 1996

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GCPS09 is a modeling tool for simulating the pattern of hourly generation and water releases from Glen Canyon Dam under various operational constraints. This program is an extension of the peakshaving model used by the Environmental Defense Fund and is primarily an educational tool. It is designed to help the user understand hydropower operations at Glen Canyon Dam and to illustrate how the alternatives examined in the Operation of Glen Canyon Dam Environmental Impact Statement affect power production, economic value, financial value, and downstream releases.

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MODELING HOURLY OPERATIONS AT GLEN CANYON DAM COLORADO RIVER STORAGE PROJECT, ARIZONA GCPS09 version 1.0

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September 1996

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Purpose

This software is primarily an educational tool. It was designed to help the user understand hourly hydropower operations at Glen Canyon Dam and to illustrate how the alternatives examined in the Operation of Glen Canyon Dam Environmental Impact Statement (GCDEIS) affect power production, economic value, financial value, and downstream releases.

Disclaimer

The algorithms used in this program provide only approximate solutions. The use of this educational program as a basis for operational decisions is not advised.

We make no warranties, express or implied, that this program or documentation are free of error, are consistent with any particular standard, or that they will meet your requirements for any particular application. This program should not be relied on for solving a problem when an incorrect solution could result in injury to a person or loss of property, whether material or monetary. If you do use the program in such a manner, it is at your own risk.

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INTRODUCTION

About Glen Canyon Dam

Glen Canyon Dam is a U.S. Bureau of Reclamation hydroelectric facility which is located on the Colorado River upstream from the Grand Canyon and is part of the Colorado River Storage Project. This facility is part of the interconnected power system in the western states. A brief description of Glen Canyon Dam and how it is operated is contained in Appendix 1. An overview of power system concepts and the role of hydropower in an interconnected system can be found in Appendix 2.

About This Program

GCPS09.EXE (c) is a modeling tool for simulating the hourly pattern of water releases and power generation from Glen Canyon Dam under various operational constraints. This program is designed as an educational tool to help users understand potential effects of operational constraints on river flows, hydropower generation, and economic and financial value.

This program is an extension of the peakshaving model used by the Environmental Defense Fund (EDF) in conjunction with the Glen Canyon Environmental Studies (GCES) Power Resources Committee for HYDROLOGY Analyses (PRC 1993).

GCPS09 simulates releases over the course of a single day. This allows the user to more fully investigate the generation, economic, financial, and flow effects of altering various constraints alone or in combination. In addition, use of a daily time step allows the timing of simulated generation and flow in relation to the onpeak period during the day to be clearly seen.

For comprehensive analyses of alternative operating criteria, the authors recommend the use of the monthly version of the peakshaving model (see Appendix 4).

Program Overview

Aggregate load is the sum of the demand for electricity across all the utilities in the interconnected system. Aggregate load is read from the default load file or other optional load file (see section entitled, "load file"). The user supplies values for various parameters which define environmental and operational constraints on hydropower generation at Glen Canyon Dam. Using the peakshaving approach (Appendix 4), GCPS09 optimally dispatches the hydro electric generation unit to meet a single day's aggregate chronological load curve subject to the specified constraint set. This produces an optimal hourly pattern of generation and release. The economic or financial value (depending on the option selected) of this hourly pattern of generation is calculated in a separate module (see Appendix 3).

Files included

GCPSDOC.007	Directions for GCPS09 in WordPerfect 5.1 format.
GCPS09.EXE	The executable program.
GCPS09.P_1	The default parameter file which contains the parameters used by GCPS09.EXE at start up.
GCPS09.P_2	The default price/minflow file which contains vectors of prices and minimum flows.
SUMMERC.DLD	The default load file which contains 24 hours of representative summer aggregate load and firm load data.
WINTERC.DLD	A file containing 24 hours of representative winter aggregate load and firm load data.
SMM1996.PRN	Spot market price vectors for water year 1996.
ALL96.PRN	Aggregate load data for additional analyses.
GCFIRM96.PRN	Firm load data for additional analyses.

Logistics

This program is designed for use in a DOS environment on IBM computers or true compatibles. GCPS09 will also run under Windows 3.x, although it has not been extensively tested in a Windows environment.

GCPS09.EXE, GCPS09.P_1, GCPS09.P_2 and SUMMERC.DLD must be present and located in the same directory on the same disk for the program to work.

Hardware required

An EGA, VGA, or SVGA graphics card is required to run this program.

General caution

GCPS09 contains several error checking routines. For the most part, these routines ensure that the user enters a number where a number is asked for and ensure that the user enters a parameter value within a reasonable range. These routines do not and cannot check for logical inconsistencies. For this reason, common sense and logic must be used to obtain meaningful results.

Parameter entry conventions

In the narrative which follows, numeric values are written with commas delimiting each thousandth place, e.g. 5,000,000. This is standard practice in American English. However, computers do not recognize commas as part of the set of numeric characters. Consequently, if this document specifies that the user is to enter an upramp rate of 5,000 cfs, the user must enter 5000. Failure to enter numbers in this manner may cause an error message or, in rare instances, a runtime error.

QUICK START

First, ensure that GCPS09.EXE, GCPS09.P_1, SUMMERC.DLD, and GCPS09.P_2 are in the same directory on the same disk. Change the default directory to this disk and directory. At the DOS prompt type:

GCPS09

Then press ENTER. This will start execution of the program. After reading the parameter file, a disclaimer will be displayed. When you have read the disclaimer, press any key to obtain the parameter menu.

```
                CURRENT RELEASE PARAMETERS
              ===================================

1.    price file = gcps09.p_2
2.    load file = summerc.dld
3.    monthly release volume (af) = 850000.00
4.    number of days in month (days) = 31
5.    reservoir elevation (feet) = 3700
6.    upramp rate (cfs/hr) = 2500.00
7.    downramp rate (cfs/hr) = 1500.00
8.    maximum flow constraint (cfs) = 20000.00
9.    minimum flow constraint (cfs) = hourly
10.   maximum daily change (cfs) = 8000.00
11.   economic option (ON=1, OFF=0) = 0
```

Figure 1. Parameter Menu and Default Parameters

The parameter values displayed in Figure 1 are the default or initial parameter values. Below the parameter menu the following message will appear, "DO YOU WANT TO CHANGE ANY OF THESE PARAMETERS (Y/N) ..." If these parameters are suitable for the intended analysis, type 'N' for NO, and ENTER.

If you need to change some of these parameters for your analysis, type 'Y' for YES, and ENTER. Then indicate the number of the parameter that you wish to change (from the parameter menu). Change the value of the parameter. If you wish to change other parameter values, repeat this process. When all of the parameters have been set to their desired values, type 'N' and ENTER.

The program will then calculate the results of the simulation. Two kinds of results will be produced: graphical and numerical.

GRAPHICAL RESULTS

The graphical results screen is presented first. Graphical results for the default parameters, price, and load files are shown in Figure 2.

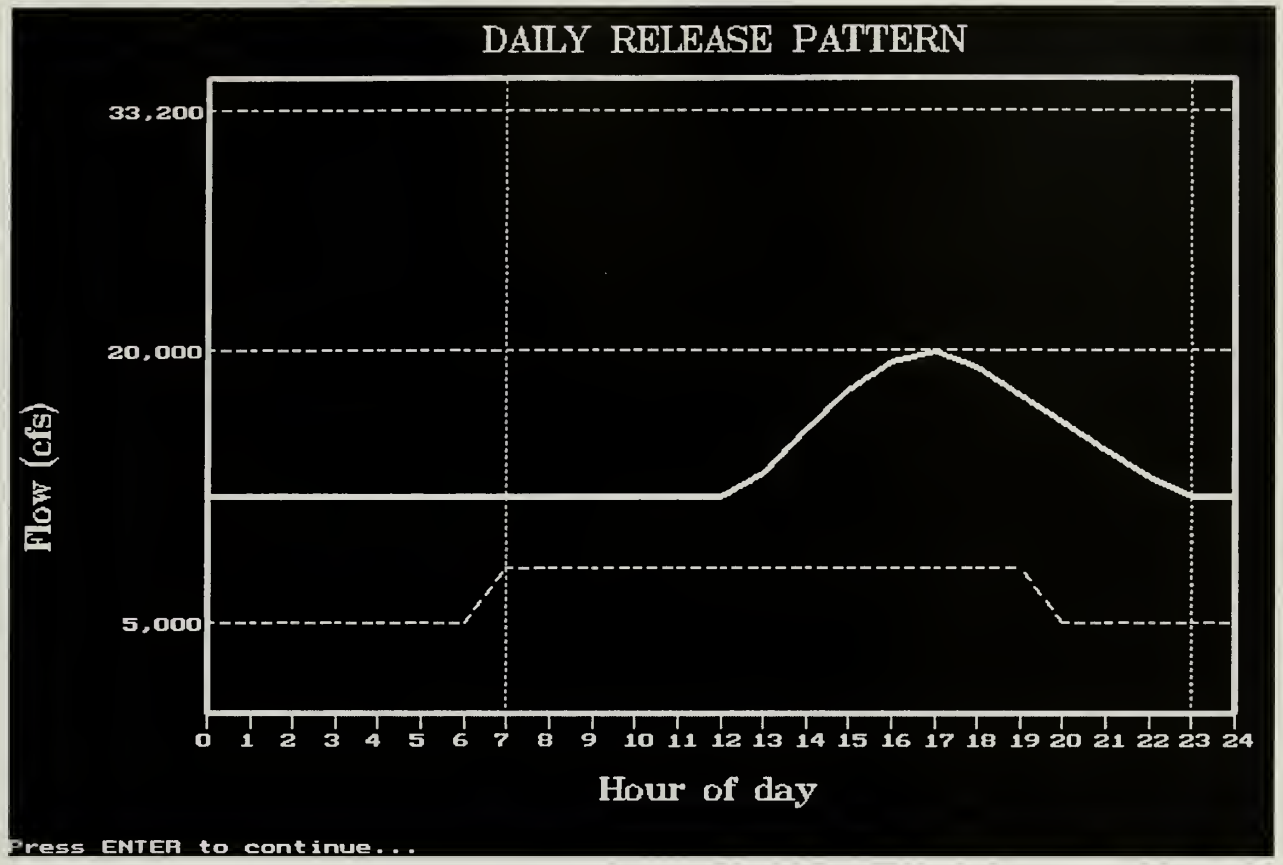

Figure 2. Graphics Output for Default Parameters, Default Price/Minflow File, and Default Load File.

The red horizontal line, shown at a flow level of 33,200 cfs, indicates the maximum powerplant release capacity. Releases in excess of this amount would require the use of the outlet works. In this program, the viewport range is static. No graphical results are shown if the user enters a monthly volume which produces flows in excess of 33,200 cfs.

The lower yellow line indicates the user-specified minimum flow in cfs. The upper horizontal yellow line indicates the lesser of (a) the user-specified maximum flow, or (b) the maximum physical capacity to make powerplant releases (see potential release).

The grey vertical lines denote the onpeak power generation period from 0700-2300 hours. In general, power is most valuable when produced during this period.

The hourly release pattern, or hydrograph, is shown in white. This pattern will be a horizontal line when the powerplant is baseloaded.

The rate of increase in flow from one hour to the next may be determined by the user-specified upramp rate. The rate of decrease in flow from one hour to the next may be determined by the user-specified downramp rate.

The maximum daily flow and capacity attained during the day is determined by the interactions of the user-specified parameters and water volume.

The difference between the highest and lowest flow is often limited by the maximum daily change constraint. For example, if the maximum daily change constraint is 8,000 cfs., the difference between the highest and lowest flow is 8,000 cfs or less.

NUMERICAL RESULTS

After the graphical results of the analysis have been presented, the numerical results are displayed, as shown in Figure 3.

```
USBR-EDF PEAK SHAVING MODEL          GCPS09.PAS                  VER_1.0   7/19/96

iter = 15

================================================================================
price file = gcps09.p_2                      upramp rate (cfs/hr)   =  2500.00
load file = summerc.dld                      downramp rate (cfs/hr) = 1500.00
                                             maximum daily change (cfs) = 8000.0
lake elevation (ft) = 3700.0
potential release (cfs) =   33200.00         max generation (MW) =    722.50
                                             min generation (MW) =    462.09
max flow constr. (cfs) = 20000.00
actual minflow  (cfs) =  19909.05            total generation (MWhr) = 12873.21
                                             spot energy (MWhr) =         149.62
min flow constr. (cfs) = hourly              dump energy (MWhr) =           0.00
actual minflow (cfs) =   11909.05
                                             financial value ($/day)  =  259264.74
monthly release volume (af) =   850000.0     spot component ($/day)   =    2629.86
target daily volume (af/day) =   27419.35    dump component ($/day)   =       0.00
actual daily volume (af/day) =   27419.13
================================================================================

Type Q to QUIT or C to CONTINUE ...
```

Figure 3. Numerical Results for Default Parameters

Iteration

"Iter" is an abbreviation for the number of major iterations made by the peakshaving algorithm. Under most circumstances, the number of iterations required to reach convergence ranges from 12 to 19. Convergence is obtained when the difference between the actual daily volume of water released, as calculated by the program, and the target daily volume of water specified by the user (see section on target daily volume) is less than 1.0e-05 times the target daily release volume. When the powerplant is baseloaded, no peakshaving is required and the number of iterations will be equal to 0. The maximum allowable number of iterations is 50. Should the algorithm fail to converge, an error message will be displayed (see section on fatal errors).

Potential release

The potential release is the lesser of either (a) 33,200 cfs or (b) the maximum attainable powerplant release given the elevation of the reservoir. This is the greatest amount of water that can be released from the dam through the powerplant.

Actual maxflow

Actual maximum flow is the highest flow that can be obtained given the physical parameters and logical constraints specified by the user. Note: if the monthly volume is sufficiently large, the actual maxflow may exceed the maximum flow constraint. If the specified monthly volume requires it, the jet tubes and/or spillways may be used to pass the required monthly volume. In this event, the user may wish to examine the specified monthly volume for accuracy and realism.

Actual minflow
Actual minimum flow is the lowest flow that was obtained during the simulation. In low release volume simulations, the actual minimum flow may be equal to the minimum flow constraint specified by the user for some or all of the hours in the day. In higher volume situations, the minimum flow is generally higher than the specified minimum flow constraint.

Target daily volume

Although the user supplies a monthly release volume, this is a daily model. The target daily volume is the amount of water available for release during a single day. In this program, a very simplistic rule is used to allocate the monthly volume across the days in the month. The target daily volume is determined by dividing the monthly volume by the number of days in the month.

Actual daily volume

The actual daily volume is the amount of water released during the simulation. Generally, this volume should be very close to the target daily volume. Small differences between the actual and target weekday volumes are an artifact of the iterative technique used to obtain a solution under certain combinations of constraints and monthly volumes.

Min generation

Minimum generation is the lowest level of electrical generation during the day, measured in megawatts (MW). Generation is calculated as shown in Appendix 5.

Max generation

Maximum generation is the highest level of electrical generation during the day, measured in megawatts (MW). Generation is calculated as shown in Appendix 5. Note that only flows that pass through the generators are used to produce power. Releases made through the jet tubes or

the spillways do not produce electrical power. It is assumed that all 8 generators are available for use.

Total generation

Total generation is the number of megawatt hours (MWhr) of electrical energy generated during the day. Total generation is the sum over the day of energy generated to meet long-term firm power needs (firmgen), energy sold on the spot market (spotgen), and dump energy (dumpgen). Total generation (TG) is described by equation 1.

$$TG = \sum_{i=1}^{24} generation_i = \sum_{i=1}^{24} [firmgen_i + spotgen_i + dumpgen_i] \tag{1}$$

Spot energy

For financial analysis purposes, spot energy (SE) is defined as the number of megawatt hours (MWhr) of energy generated during the day in excess of firm load requirements and is calculated as shown in equations 2 and 3. Hourly firm load requirements for the simulation are read from the load file. Hourly firm load in this file is 0.70 of the Salt Lake City Area Integrated Projects (SLCA/IP) total firm load. Spot energy is assumed to be sold on the spot market at spot market prices. Spot market generation is a component of total generation.

$$spotgen_i = \begin{cases} 0, & \text{if } generation_i \le firmload_i \\ generation_i - firmload_i, & \text{if } generation_i > firmload_i \le aggload_i \\ aggload_i - firmload_i, & \text{if } generation_i > aggload_i \end{cases} \tag{2}$$

$$SE = \sum_{i=1}^{24} spotgen_i \tag{3}$$

If the economic option is enabled (option=1), all power is assumed to be sold in the spot market. Therefore, spot energy and total energy will be identical in this case.

Dump energy

Aggregate load is the sum of the demand for electricity across all the utilities in the interconnected system (see section entitled, "load file"). For financial analysis purposes, dump energy (DE) is defined as the number of megawatt hours (MWhr) of energy generated during the

day in excess of aggregate load. Dump energy is assumed to be sold outside the system at dump energy prices, which are usually quite low. The price for dump energy is read from the default parameter file, GCPS09.P_1, illustrated in Appendix 6. Dump energy is a component of total generation. Under most circumstances, no dump energy will be produced. A non-zero value for dump energy is an indication that generation exceeds aggregate load during at least one hour of the day. This may occur if minimum flows are high relative to aggregate load or may indicate another analysis problem which requires consideration. Also see, "Warning Messages—Minimum flow constraint exceeds some loads."

$$dumpgen_i = \left\{ \begin{array}{ll} 0, & if\ generation_i \leq aggload_i \\ generation_i - aggload_i, & if\ generation_i > aggload_i \end{array} \right\} \quad \textbf{(4)}$$

$$DE = \sum_{i=1}^{24} dumpgen_i \quad \textbf{(5)}$$

Financial value

When the economic option is disabled (option=0), the financial value of the power produced during the simulation is calculated and displayed. The vectors of hourly prices used in this calculation are contained in the file named GCPS09.P_2. The contents of this file are illustrated in Appendix 8. Note that financial value is measured in dollars per day. Further information about this measure and how to interpret it may be found in Appendix 3.

Spot component

If the financial value is calculated, the component of gross financial value derived from spot market sales is calculated and displayed. The price vector used is contained in the file named GCPS09.P_2, the contents of which are illustrated in Appendix 8. Note that the spot component is measured in dollars per day. Further information about this measure and how to interpret it may be found in Appendix 3.

Dump component

If the financial value is calculated, the component of gross financial value derived from dump energy sales is calculated and displayed. The price used is contained in the file named GCPS09.P_1, the contents of which are illustrated in Appendix 6. Note that the dump energy component of financial value is measured in dollars per day. Further information about this measure and how to interpret it may be found in Appendix 3.

Economic value

When the economic option is enabled (option=1), the economic value of the power produced during the simulation is calculated and displayed. When this option is enabled, all of the energy generated is assumed to be sold on the spot market at spot market prices. The vector of hourly prices used for calculating the economic value of the power produced is contained in the file named GCPS09.P_2. The contents of GCPS09.P_2 are illustrated in Appendix 8. Note that economic value is measured in dollars per day. Further information about this measure and how to interpret it may be found in Appendix 3.

WARNING MESSAGES

Powerplant baseloaded

This message indicates that releases (and power generation) are constant across all hours of the day. This condition occurs when the monthly volume specified by the user produces an average daily flow within 25 cfs of the maximum release constraint specified or produces an average daily flow within 25 cfs of the maximum release physically possible (see also: potential release).

Opening jet tubes

The outlet works at Glen Canyon Dam consist of two spillways and four hollow jet tubes. The four hollow jet tubes have a combined release capacity of 15,000 cfs. This message indicates that the user-specified monthly release volume produces average flows exceeding powerplant capacity (33,200 cfs) but less than the combined capacity of the generators and the hollow jet tubes (33,200 cfs + 15,000 cfs = 48,200 cfs). This necessitates opening the jet tubes. Water which is released through the jet tubes is "spilled" and does not generate electricity. From a power production standpoint, this is undesirable. If this warning message appears, the user may wish to re-examine the monthly volume specified and verify that it is realistic.

Opening spillways

The outlet works at Glen Canyon Dam consist of two spillways and four hollow jet tubes. The four hollow jet tubes have a combined release capacity of 15,000 cfs and the two spillways have a combined release capacity of 240,000 cfs. This message indicates that the user-specified monthly volume produces average flows exceeding 48,200 cfs which necessitates opening the spillways. Since this condition has occurred only a few times since the dam was constructed, the user may wish to re-examine the monthly volume specified if this message appears.

Flashboards in use

This message indicates that the user-specified lake elevation exceeds the current full pool level of 3,700 feet above mean sea level. Elevations in excess of 3,700 feet would require the installation of flashboards on the spillways. Actual installation of these flashboards would require National Environmental Policy Act (NEPA) compliance due to potential impacts on natural and cultural resources around Lake Powell.

Minimum flow exceeds some loads

This message indicates that the user supplied aggregate load curve is exceeded by the minimum flow constraint for at least one hour. A non-zero value for dump energy will appear in the results following this message. While it may be the case that the minimum flow constraint is sufficiently high that dump energy results, this message is more likely to indicate an inconsistency in the analysis. In particular, careful consideration should be given to the nature of the load curves being used for the simulation.

Zero or negative aggregate loads in load file

This message indicates that the user supplied load file contains some nonpositive aggregate loads or that the format for the file is incorrect. When this message appears, the resulting analysis is meaningless.

Firm loads exceed aggregate load

This message indicates that the user supplied load file contains some firm loads which exceed the aggregate load in that hour or that the format for the file is incorrect. When this message appears, the resulting analysis is meaningless.

Zero or negative firm loads in load file

This message indicates that the user supplied load file contains some nonpositive firm loads or that the format for the file is incorrect. When this message appears, the resulting analysis is meaningless.

USER-SPECIFIED PARAMETERS

Price file

The default price vectors used in the analysis are contained in the file named GCPS02.P_2. This file contains a column vector of 24 primary prices (pprice) and a column vector of 24 spot market prices (sprice).

The primary prices used in the default price file are the current Salt Lake City Area Integrated Power (SLCA/IP) wholesale firm power rate. This firm power rate, known as the SLIP-F5 rate, was established by Western Area Power Administration (Western) on December 1, 1994. It should be noted that this rate is cost based and may be less than or greater than the spot market price in any particular hour. The SLCA/IP wholesale firm power rate reflects both fixed and variable costs across CRSP and related projects.

Spot market prices are extremely volatile and vary considerably by location. Consequently, it is often difficult to obtain spot price data which is sufficiently disaggregated for analysis purposes. The spot market prices used here were estimated using Argonne National Laboratory's Spot Market Network Model (VanKuiken et al. 1994) as employed for Western's Power Marketing EIS (Western 1996). These spot market prices are August 1998 estimated hourly mean weekday prices deflated to 1996 dollars using the forecast producer price index for electricity (0.8613). Spot market prices are used in various analyses to represent the short-run value of power (e.g., Reclamation 1996). Note that spot market prices most closely approximate the marginal or variable cost of electrical power. These prices do not represent the long-term replacement cost of power, which must include both a fixed and variable cost component.

The vectors of prices contained in GCPS09.P_2 can be altered by the user with a text editor. Alternatively, a user created input file can be created and used for analysis. Price vectors for other months of water year 1996 are shown in Appendix 9 and are contained in the file named SMM1996.PRN, which was supplied with this program.

Further information on the use of prices in the calculation of economic value, financial value, and spot market revenues is contained in Appendix 3.

Load file

The August 1996 aggregate hourly load data contained in the default file were constructed from 1994 hourly load data reported by Salt River Project, Platte River Power Authority, Colorado Springs Utilities, and Deseret Generation and Transmission. These publicly available data were provided to the Federal Energy Regulatory Commission on form 714. The 1994 load data were escalated by 2 percent per annum to account for load growth and adjusted for the number of days and the pattern of weekdays and weekends in 1996. These load data were used for the analysis described in Reclamation (1996).

The August hourly firm load data contained in the default file were obtained from Western Area Power Administration's Supervisory Control and Data Acquisition (SCADA) system, line number 1172. These data represent the total SLCA/IP firm load in 1995. For analysis purposes, it is assumed that Glen Canyon Dam supplies 70 percent of the SLCA/IP firm load.

The default load file is representative of summer conditions. A representative winter load file is also furnished with this program. This optional load file, named WINTERC.DLD, is shown in Appendix 11. Additional aggregate load and firm load data for water year 1996 can be found in the files named ALL96.PRN and GCFIRM96.PRN, which were supplied with this program.

Monthly release volume

All other things being equal, the amount of water available for release during any given month determines the maximum release (or capacity) and the minimum release from Glen Canyon Dam.

The user can enter a wide range of monthly release volumes for analysis purposes. Typically, Glen Canyon releases range from about 500,000 af per month to about 2,500,000 af per month.

Monthly volumes entered by the user are tested to ensure that they are sufficient to allow the specified minimum flow to be met. If not, a warning message will appear prompting the user to increase the monthly volume (or reduce the minimum flow constraint). Appendix 12 contains the allowable range of input values for this parameter.

Note: monthly release volume, reservoir elevation, and maximum daily change are not independent parameters. It is up to the user to determine realistic combinations of these parameters.

Number of days in month

Given the monthly release volume, the number of days in any given month determines the amount of water that is released in any particular day. For example, if the monthly release volume is 500,000 af and there are 28 days in the month, the average daily release would be 500,000/28 = 17,857.1 af per day. Appendix 12 contains the allowable range of input values for this parameter.

It should be noted that operators do not typically release the same amount of water every day. The demand for electricity varies seasonally and is lower on weekends and holidays than it is on weekdays. The profit maximizing hydroproducer considers the expected load pattern, market conditions and the availability of other energy when patterning releases during the day, week, and month. See Appendices 2 and 4 for further information.

Reservoir elevation

The elevation of Lake Powell determines the amount of head available to run the generators. The reservoir is full at 3700 feet above mean sea level, and the maximum amount of water that can be released through the powerplant when the reservoir is full is 33,200 cfs. As the level of the reservoir decreases, the distance from the surface of the lake to the tailrace falls— reducing the gross head. Correspondingly less water can physically be released from the dam as the reservoir elevation falls.

In addition, the elevation of generator intakes and the outlet works constrain monthly release volumes in certain elevation ranges. Power cannot be generated if the reservoir surface elevation falls below an elevation of 3,490 feet. The jet tubes are located at elevation 3,500 feet. If lake elevations fall below this level, water cannot be released through the jet tubes. The spillways are located at elevation 3,648 feet. The spillways cannot be used if the reservoir falls below that elevation.

A warning message will appear if the user specifies a lake elevation that is incompatible with a specified release volume. For example, if the user specifies a lake elevation of 3,495 feet and a monthly release volume that exceeds powerplant capacity, a warning message will appear. If this message appears, the user should re-examine the monthly volume specified and the lake level specified. Appropriate adjustments must be made. Appendix 12 contains the allowable range of input values for this parameter.

This program uses the methods described in Reclamation (1988, sections 3.38.2-3.38.5 and 1987, sections 9.1-9.2) to calculate effective head and maximum attainable release. On the output screen, maximum attainable powerplant release is described as "potential release."

Again, it cannot be overemphasized that reservoir elevation is not independent of monthly release volume. For instance, high discharges are unlikely to occur under low reservoir conditions. Spills will never occur under low reservoir conditions. Thus, the user must make realistic and informed choices for reservoir elevation in combination with other related parameters.

Upramp rate

This is the rate at which the flow can be increased from one level to a higher level measured over an hour. Historically, the upramp rate ranged from 1,000 cfs/hr to 33,200 cfs/hr. All other things being equal, the greater the upramp rate, the higher the maximum release that can be achieved. Conversely, a lower or more restrictive upramp rate will result in lower maximum releases. Appendix 12 contains the allowable range of input values for this parameter.

Downramp rate

This is the rate at which the flow can be decreased from one level to a lower level measured over an hour. Historically, the downramp rate ranged from 1,000 cfs/hr to 33,200 cfs/hr. All other things being equal, the greater the downramp rate, the higher the maximum release that can be achieved. Conversely, a lower, or more restrictive, downramp rate will result in a lower maximum release. Appendix 12 contains the allowable range of input values for this parameter.

Maximum flow constraint

This parameter places an upper limit on the amount of water, measured in cfs, that can be released from the dam under normal operating conditions. Under conditions where monthly release volumes are quite high, this constraint may be exceeded to achieve the monthly release volume specified by the user. In the event that the indicated monthly volume requires the powerplant to be baseloaded, a warning message will be displayed. In the event that the monthly release volumes are so large that the jet tubes or spillways must be opened, appropriate warning messages are displayed. Appendix 12 contains the allowable range of input values for this parameter.

In cases where the reservoir elevation is sufficiently low and the maximum flow constraint is sufficiently large, the physical capacity to release water may be less than the maximum flow constraint.

Minimum flow constraint

This parameter places a lower limit on the amount of water measured in cfs that can be released from the dam under normal operating conditions. The minimum flow constraint can differ for each hour of the day. This program requires the user to input monthly release volumes which are at least large enough to meet this constraint. If the user-specified monthly release volume is insufficient to meet this constraint, the program will calculate the volume required to meet the indicated minimum flow and an error message will appear. Appendix 12 contains the allowable range of input values for this parameter.

The default vector of minimum flows used by the program is contained in the file named GCPS09.P_2. Alternatively, the minimum flow can be changed by using the parameter menu. However, changing the minimum flow constraint through the parameter menu allows the use of only a single value for all 24 hours during the day. If hourly varying minimum flows different from those found in the default file are desired, the user will need to alter the vector of minimum flows found in GCPS09.P_2 using a text editor. See the section entitled, "user created input files."

Under many combinations of release parameters, releases will be above the minimum flow constraint.

Maximum daily change constraint

The maximum daily change constraint limits the amount of flow fluctuation in any given day. In practice, this constraint is often the limiting constraint (in a mathematical programming sense). When there is a restrictive maximum daily change constraint, the difference between the maximum flow and the minimum flow is often limited by the magnitude of this constraint. For example, if the maximum daily change constraint is 8,000 cfs, the difference between the maximum flow and the minimum flow is always 8,000 cfs or less. Appendix 12 contains the allowable range of input values for this parameter.

For steady flow alternatives, the maximum daily change should be set to 0.0.

ANALYSIS OF GCDEIS ALTERNATIVES

Users should refer to the Glen Canyon Dam Final EIS (Reclamation 1995) for the details of all alternatives to ensure meaningful results. A summary of the GCDEIS alternatives can be found in Appendix 13.

No Action Alternative

For the No Action Alternative (NA), enter 31,500 for the maximum flow, 33,200 for the upramp rate, the downramp rate, and the maximum daily change. Enter 1,000 or 3,000 for the minimum flow constraint (see Appendix 13). Enter all other user-specified parameters for the analysis being undertaken.

```
          RELEASE PARAMETERS FOR NA ALTERNATIVE
          =====================================

     1.   price file = gcps09.p_2
     2.   load file = summerc.dld
     3.   monthly release volume (af) = 850000
     4.   number of days in month (days) = 31
     5.   reservoir elevation (feet) = 3700
     6.   upramp rate (cfs/hr) = 33200
     7.   downramp rate (cfs/hr) = 33200
     8.   maximum flow constraint (cfs) = 31500
     9.   minimum flow constraint (cfs) = 1000 or 3000
     10.  maximum daily change (cfs) = 33200
     11.  economic option (on=1, off=0) = 0
```

Parameters in **bold** must be changed to the values indicated. The default values of the other parameters are shown. These should be changed by the user for specific analyses.

Steady Flow Alternatives

For any of the steady flow alternatives; Seasonally Adjusted Steady Flow (SASF), Existing Monthly Volume Steady Flow (EMV), and Year Round Steady Flow (YRSF)— enter 0.0 for the maximum daily change, 33,200 for the maximum flow constraint, and, 8,000 to 18,000 for the minimum flow constraint. For the specifics of each alternative, see Appendix 13. Enter all other user-specified parameters for the analysis being undertaken. Note that ramp rates are not applicable to analyses of the steady flow alternatives.

```
          RELEASE PARAMETERS FOR STEADY FLOW ALTERNATIVES
           ===================================

     1.    price file = gcps09.p_2
     2.    load file = summerc.dld
     3.    monthly release volume (af) = 850000
     4.    number of days in month (days) = 31
     5.    reservoir elevation (feet) = 3700
     6.    upramp rate (cfs/hr) = 2500.00
     7.    downramp rate (cfs/hr) = 1500.00
     8.    maximum flow constraint (cfs) = 33200
     9.    minimum flow constraint (cfs) = 8000 to 18000
     10.   maximum daily change (cfs) = 0.0
     11.   economic option (ON=1, OFF=0) = 0
```

Parameters in **bold** must be changed to the values indicated. The default values of the other parameters are shown. These should be changed by the user for specific analyses.

Maximum Powerplant Capacity Alternative

For the Maximum Powerplant Capacity alternative (MPPC), enter 33,200 for the maximum flow, the upramp rate, the downramp rate, and the maximum daily change. Enter 1,000 or 3,000 for the minimum flow constraint (see Appendix 13). Enter all other user-specified parameters for the analysis being undertaken.

```
        RELEASE PARAMETERS FOR MPPC ALTERNATIVE
        ===================================

1.      price file = gcps09.p_2
2.      load file = summerc.dld
3.      monthly release volume (af) = 850000
4.      number of days in month (days) = 31
5.      reservoir elevation (feet) = 3700
6.      upramp rate (cfs/hr) = 33200
7.      downramp rate (cfs/hr) = 33200
8.      maximum flow constraint (cfs) = 33200
9.      minimum flow constraint (cfs) = 1000 or 3000
10.     maximum daily change (cfs) = 33200
11.     economic option (ON=1, OFF=0) = 0
```

Parameters in **bold** must be changed to the values indicated. The default values of the other parameters are shown. These should be changed by the user for specific analyses.

High Fluctuating Flow Alternative

For the High Fluctuating Flow alternative (HFF), enter 31,500 for the maximum flow and 33,200 for the upramp rate. The maximum daily change should be 15,000 to 22,000 cfs (see Appendix 13). The downramp rate should be either 4,000 or 5,000 cfs (see Appendix 13). The minimum flow constraint should be 3,000, 5,000, or 8,000. Enter all other user-specified parameters for the analysis being undertaken.

```
        RELEASE PARAMETERS FOR HFF ALTERNATIVE
      ===================================

1.    price file = gcps09.p_2
2.    load file = summerc.dld
3.    monthly release volume (af) = 850000
4.    number of days in month (days) = 31
5.    reservoir elevation (feet) = 3700
6.    upramp rate (cfs/hr) = 33200
7.    downramp rate (cfs/hr) = 4000 or 5000
8.    maximum flow constraint (cfs) = 31500
9.    minimum flow constraint (cfs) = 3000, 5000, or 8000
10.   maximum daily change (cfs) = 15000 to 22000
11.   economic option (ON=1, OFF=0) = 0
```

Parameters in **bold** must be changed to the values indicated. The default values of the other parameters are shown. These should be changed by the user for specific analyses.

Moderate Fluctuating Flow Alternative

In the case of the Moderate Fluctuating Flow alternative (MFF), the maximum daily change constraint varies with the monthly volume. The maximum daily change constraint should be set as follows. First, based on the monthly volume available, determine the mean monthly release X, in cfs. The maximum daily change constraint should be set at the greater of X-6,000 or X-.45*X. The upramp rate should be set to 4,000, the downramp rate to 2,500, and the minimum flow constraint should be set to 5,000. Enter all other user-specified parameters for the analysis being undertaken.

```
          RELEASE PARAMETERS FOR MFF ALTERNATIVE
        =====================================

1.    price file = gcps09.p_2
2.    load file = summerc.dld
3.    monthly release volume (af) = 850000
4.    number of days in month (days) = 31
5.    reservoir elevation (feet) = 3700
6.    upramp rate (cfs/hr) = 4000
7.    downramp rate (cfs/hr) = 2500
8.    maximum flow constraint (cfs) = 31500
9.    minimum flow constraint (cfs) = 5000
10.   maximum daily change (cfs) = various
11.   economic option (ON=1, OFF=0) = 0
```

Parameters in **bold** must be changed to the values indicated. The default values of the other parameters are shown. These should be changed by the user for specific analyses.

Modified Low Fluctuating Flow Alternative

In the case of the Modified Low Fluctuating Flow alternative (MLFF), the maximum daily change constraint is dependent on the monthly release volume. Set the maximum daily change to 5,000, 6,000, or 8,000 cfs, as shown in Appendix 13. Set the upramp rate to 4,000 cfs and the downramp rate to 1,500. Set the maximum flow constraint to 25,000 cfs. Set the minimum flow constraint to 8,000 cfs. Set all other parameters in accordance with the interim low fluctuating flow alternative (iLFF), as shown in Appendix 13.

```
     RELEASE PARAMETERS FOR MLFF ALTERNATIVE
   ===================================

1.    price file = gcps09.p_2
2.    load file = summerc.dld
3.    monthly release volume (af) = 850000
4.    number of days in month (days) = 31
5.    reservoir elevation (feet) = 3700
6.    upramp rate (cfs/hr) = 4000
7.    downramp rate (cfs/hr) = 1500
8.    maximum flow constraint (cfs) = 25000
9.    minimum flow constraint (cfs) = 8000
10.   maximum daily change (cfs) = 5000, 6000, or 8000
11.   economic option (ON=1, OFF=0) = 0
```

Parameters in **bold** must be changed to the values indicated. The default values of the other parameters are shown. These should be changed by the user for specific analyses.

Interim Low Fluctuating Flow Alternative

For the Interim Low Fluctuating Flow alternative (iLFF), the maximum daily change constraint is dependent on the monthly release volume, as shown in Appendix 13. Set the upramp rate to 2,500 cfs and the downramp rate to 1,500. Set the maximum flow constraint to 20,000 cfs. Set the minimum flow constraint to 8,000 cfs. Set all other parameters in accordance with the analysis you are undertaking.

```
RELEASE PARAMETERS FOR iLFF ALTERNATIVE
   ===================================

1.    price file = gcps09.p_2
2.    load file = summerc.dld
3.    monthly release volume (af) = 850000
4.    number of days in month (days) = 31
5.    reservoir elevation (feet) = 3700
6.    upramp rate (cfs/hr) = 2500
7.    downramp rate (cfs/hr) = 1500
8.    maximum flow constraint (cfs) = 20000
9.    minimum flow constraint (cfs) = 8000
10.   maximum daily change (cfs) = 5000, 6000, or 8000
11.   economic option (ON=1, OFF=0) = 0
```

Parameters in **bold** must be changed to the values indicated. The default values of the other parameters are shown. These should be changed by the user for specific analyses.

OTHER TOPICS

Other parameters

The physical parameters of the facility, such as the design maximum release from the generators (33,200 cfs), the capacity of the jet tubes (15,000 cfs), the capacity of the spillways (240,000 cfs), and the height of the spillways cannot be altered by the user.

Parameter defaults

The file, GCPS09.P_1, contains the initial parameters loaded by the program at runtime and displayed on the parameter menu. If so desired, the value of the parameters in this file can be altered by the user with a text editor, or a new parameter file can be constructed (see user created input files). Appendix 6 contains the default parameters for version 1.0 of this program, dated 7/19/96.

User created input files

To facilitate their own analyses, users can create alternate versions of the input files (GCPS09.P_1, GCPS09.P_2, SUMMERC.DLD) used by this program. User created input files must mirror the format of the files supplied with this program (see Appendices 6, 8, 10 and 11 for examples of these formats). An incorrect format will cause a runtime error. Reference to a backup version of the original file will often point to the cause of the error. It is highly recommended that backup versions of the input files be made just in case some formatting problem arises.

Unlike parameter values entered using the menu, there is no range checking or error checking for parameters read from input files. An incorrect format or out of range parameter value will cause a runtime error. Note that Appendix 12 contains the allowable ranges for all user specified parameters.

Fatal errors

user supplied volume exceeds load

The area under the aggregate load curve is equal to the total amount of energy demanded during a day. This area can be converted from an energy measure to an equivalent water volume by solving the equation shown in Appendix 5 for the flow rate (cfs) and converting the resulting flow rate to an acre foot measure. If the user supplied water volume exceeds the water volume implied by the aggregate load curve (a) it is likely that the analyst has made a logic error, (b) the peakshaving model cannot converge to a unique

solution, (c) this error message appears, and (d) the program halts.

ps algorithm failure

In some extremely rare circumstances, the peakshaving algorithm may fail to converge. Should this occur, this error message will be issued and all subsequent output, if any, is meaningless. If this condition can be replicated, please record the values of all parameters and call for technical assistance.

Program failures

Although this program has been tested extensively, it is possible that some unforeseen runtime errors may occur during use. If a runtime error or other failure occurs, (1) record the error message and the runtime error code number, (2) record the values of all parameters at the time of the mishap (use PRINT SCRN for example), and (3) see if you can consistently cause this error to occur.

If you have faithfully completed steps 1, 2, and 3, above, without resolution of the problem, call for technical assistance.

Technical assistance

To report errors or obtain technical assistance contact:

David A. Harpman
U.S. Bureau of Reclamation
P.O. Box 25007 (D-8270)
Denver, CO 80225
(303) 236-8080 x539 [voice]
(303) 236-5974 [FAX]
dharpman@do.usbr.gov [e-mail]

Known program deficiencies

1. Entry of non-numeric characters when numerical entries are required may result in various implicit or explicit errors. Most of these errors are trapped and corrected by the program,

but others are not. For example, entry of the string '5,000,000' may cause an error message. Where a numeric response is requested, enter only numeric characters. For example, if this manual indicates that you should enter an upramp rate of 4,000 cfs, enter, 4000. See the section on parameter entry conventions in the front of this manual.

2. Because the graphics results are plotted to the nearest hour, the graphics results may not correspond exactly with the numerical results. The numerical results should be used for any subsequent analyses.

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APPENDIX 1. GLEN CANYON DAM

Background

Glen Canyon Dam was completed by the U.S. Bureau of Reclamation in 1963. It is located on the Colorado River, upstream from the Grand Canyon. This 710 foot high concrete arch dam controls a drainage basin of approximately 108,335 square miles. There are eight hydroelectric generators at the dam, which, following the 1985 uprate and rewind, can produce up to 1,288.2 MW of electric power at a 95 percent power factor (Reclamation 1982). Further details about the structure and design of Glen Canyon Dam can be found in Reclamation (1970) and Water and Power Resources Service (1981).

Power operations

Glen Canyon Dam is an integral part of the Colorado River Storage Project (CRSP) which was authorized in 1956. The energy and capacity from CRSP is marketed by the Western Area Power Administration (Western) as part of the Salt Lake City Area Integrated Power (SLCA/IP) system. There are 12 hydroelectric facilities in the SLCA/IP system, with a combined generation capacity of 1,796.61 MW. Glen Canyon Dam makes up 71.7 percent of the installed capacity of this system.

The power produced in the SLCA/IP system and purchased by Western from other sources is sold primarily to about 180 long-term, firm power customers, which in turn, serve approximately 1.7 million residential, industrial, agricultural, and municipal end use customers across a six state area. This power is provided to Western's customers under contracts which establish the terms for how capacity and energy are to be sold. These contracts also specify the levels of capacity and energy that Western agrees to offer for long-term (greater than 12 months) sale. In aggregate, these amounts constitute Western's "commitment level." The capacity and energy level is called firm when it is guaranteed to customers. Western agreed to deliver SLCA/IP winter and summer capacity to long-term firm power customers in a marketing arrangement known as the Post-1989 Allocation (Western 1989). That planned marketing arrangement has been enjoined by court order pending completion of an Environmental Impact Statement (Western 1996), a record of decision, and subsequent legal challenges, if any. The current contract rate of delivery (CROD) is known as the interim allocation. Aggregate capacity commitments for both the interim allocation and the Post-1989 Allocation are shown in Table 1-1. These contractual arrangements, the methodology used for determining firm capacity and energy levels, and the amount of energy and capacity allocated to each customer are described in detail in Western (1989) and preceding documents.

Regardless of the CROD commitment level eventually implemented, the power sold to Western's customers is priced administratively to recover production costs, maintenance costs, and Colorado River Storage Project costs allocated to power. The administrative price may be less than, greater than, or equal to the market value of this power. The current SLCA/IP composite rate of $20.17

/MWhr was established on December 1, 1994. This wholesale rate is often compared with current spot market prices (Appendix 9). However, because of the long-term nature of these contract allocations, the SLCA/IP price is more correctly compared with the price of long-term thermal capacity which is approximately $60.00 to $90.00 /MWhr.

Table 1-1. SLCA/IP Long-Term Firm Capacity Allocations

	Interim Allocation (kW)	Post-1989 Allocation (kW)
Winter (October-March)	1,291,232	1,406,532
Summer (April-September)	1,269,891	1,314,130

Western sells power to its firm customers at the SLCA/IP rate up to the amount of their allocation. If customers require additional energy, and additional generation is available, Western may sell short-term power to them at a price ranging from the SLCA/IP rate to the spot market rate, depending on market conditions. If generation exceeds the needs of firm power customers, energy may be exchanged with other suppliers or sold on the spot market. If SLCA/IP generation is less than long-term firm power commitments, Western must purchase replacement power on the spot market, make short-term contractual purchases, or borrow energy from other suppliers to make up the deficit. A more detailed discussion and a simulation of contract and spot market transactions may be found in Veselka, Hamilton, and McCoy (1995).

Environmental concerns

Historically, Glen Canyon Dam was operated primarily as a load following unit to produce peaking power. Operation of the dam to produce peaking power results in hourly fluctuations in release and river stage. These fluctuations have been shown to significantly affect the quality of whitewater boating, angling, and the maintenance of the downstream trout fishery (GCES 1988, National Academy of Sciences 1987). Unconstrained daily variations in flow have also been implicated in the depletion of pre-dam alluvial deposits, with associated impacts on cultural and riparian resources. Species which evolved in a warm, sediment rich environment now face cold clear conditions with daily fluctuations in flow and river stage. Two long-lived native fish species have been extirpated and several others are now endangered (Reclamation 1995).

Interim operations

Concerns for downstream environmental resources resulted in the establishment of "Interim Flows" by the Secretary of the Interior in November 1991 (Reclamation 1991). This operational regime is much more restrictive than historical operations. The parameters which describe this operation are described in Appendix 13.

The Operation of Glen Canyon Dam Environmental Impact Statement (GCDEIS) was initiated in 1989 to examine options which, "... minimize-- consistent with law-- adverse impacts on downstream environmental and cultural resources and Native American interests...". The environmental impacts of nine operational alternatives are examined in the final GCDEIS, which was issued in 1995 (Reclamation 1995). These alternatives range from unrestricted operations to baseloading of the powerplant.

Future operations

The Secretary of the Interior is charged with selecting an alternative which strikes a balance between the environment and economic effects. Based on the final GCDEIS, pertinent published and unpublished documents, and additional information, the Secretary is expected to issue a record of decision (ROD) in 1996. The ROD will specify the way in which Glen Canyon Dam is operated in the future. Until a new operational alternative is selected and a Record of Decision is issued, it is anticipated that Interim Flows will remain in effect.

APPENDIX 2. POWER SYSTEM CONCEPTS.

Terms

In the language of the utility industry, the aggregate demand for electricity is known as "load." Load varies on a monthly, weekly, daily, and hourly basis. During the year, the aggregate demand for electricity is highest in the winter and summer when heating and cooling needs, respectively, are greatest. Load is less in the spring and fall which are known as "shoulder months." During a given week, the demand for electricity is typically higher on a weekday, with less demand on weekends, particularly holiday weekends. During a given day, the aggregate demand for electricity is relatively low from midnight through the early morning hours, rises sharply during working hours, and falls off during the late evening.

Power is most valuable when it's most in demand— during the day when people are awake and industry and businesses are operating. This is called the "onpeak period." In the West, the onpeak period is defined as the hours from 7:00 a.m. to 11:00 p.m., Monday through Saturday. All other hours are considered to be offpeak.

Baseload power demand is the minimum amount of electricity which is demanded on a more-or-less continuous basis throughout the day. Collectively, electrical devices such as refrigerators, which operate during all hours, are largely responsible for this demand. Intermittent and periodic electrical demand makes up the remaining demand for power. Because electrical energy cannot be stored on a large scale, demand must be satisfied by power produced when it is needed.

The rate at which a powerplant can change from one generation level to another is called a "ramp rate." This is typically measured by the change in megawatts over a one hour period. Ramp rates vary widely depending on the type of powerplant and its design. In addition, ramp rates may be constrained for engineering, institutional, or environmental reasons.

The maximum amount of electricity which can be produced by a powerplant is called it's capacity. Capacity is ordinarily measured in megawatts (MW). The capacity of fossil fuel and nuclear powerplants is determined by their design and is fixed over time. In the case of hydroelectric powerplants, capacity varies over time because it is a function of reservoir elevation, tailwater elevation, and the design of the facility.

Supply side resources

In the West, there are four types of powerplants commonly used to supply electricity. These are coal plants, nuclear plants, gas turbine plants, and hydroelectric plants. Each of these has different operating characteristics, capital, and variable costs. In general, coal and nuclear plants are very costly to construct but are relatively inexpensive to operate. Due to their design features, nuclear powerplants cannot rapidly change output (i.e.: have low ramp rates), are used primarily to supply baseload power. Although coal plants do have some limited capability to change

generation levels, it is very costly to stop and restart them. For instance, it may take three days or more to "cold start" a baseload coal plant. Consequently, both of these types of plants are used at a more or less constant output level to supply baseload power.

In contrast, gas turbine plants are relatively inexpensive to construct but are quite expensive to operate. Because of their high cost of operation and their ability to rapidly change output (i.e.: have high ramp rates), they are most often used to supply power during high demand onpeak hours.

Hydropower plants are relatively expensive to construct but their variable cost of operation is extremely low. There are two types of hydroelectric plants: run of river plants and peaking power plants. Run of river plants generate power in proportion to the timing and amount of runoff. In contrast, peaking plants are designed to rapidly change generation levels in order to satisfy changes in the demand for electricity. This capability is termed "load following."

Hydropower plants can generate electricity without causing air pollution or using nonrenewable fuels. Peaking hydropower plants are particularly valuable because when they are used to generate power during onpeak periods there is less need to operate expensive thermal peaking plants such as gas turbine units.

Hydro and the interconnected system

Explicitly or through market forces, coal plants, nuclear plants, gas turbine units, and hydropower plants operate in a complementary manner to supply electricity to meet aggregate demand. Figure 4 illustrates graphically the use of these plants to meet load across a representative week in August. As shown in Figure 4, run of river hydroplants, nuclear, and coal plants are used to meet baseload power needs. Onpeak power needs are met by gas turbine units and hydropower plants. The black shaded area is the energy produced by the hydropower resource. If more water were available for release, this area would be correspondingly larger and less onpeak energy would be produced by expensive gas turbine units. If less water were available for release, this area would be smaller and gas turbine units would be used to produce more of the onpeak energy needed to meet demand.

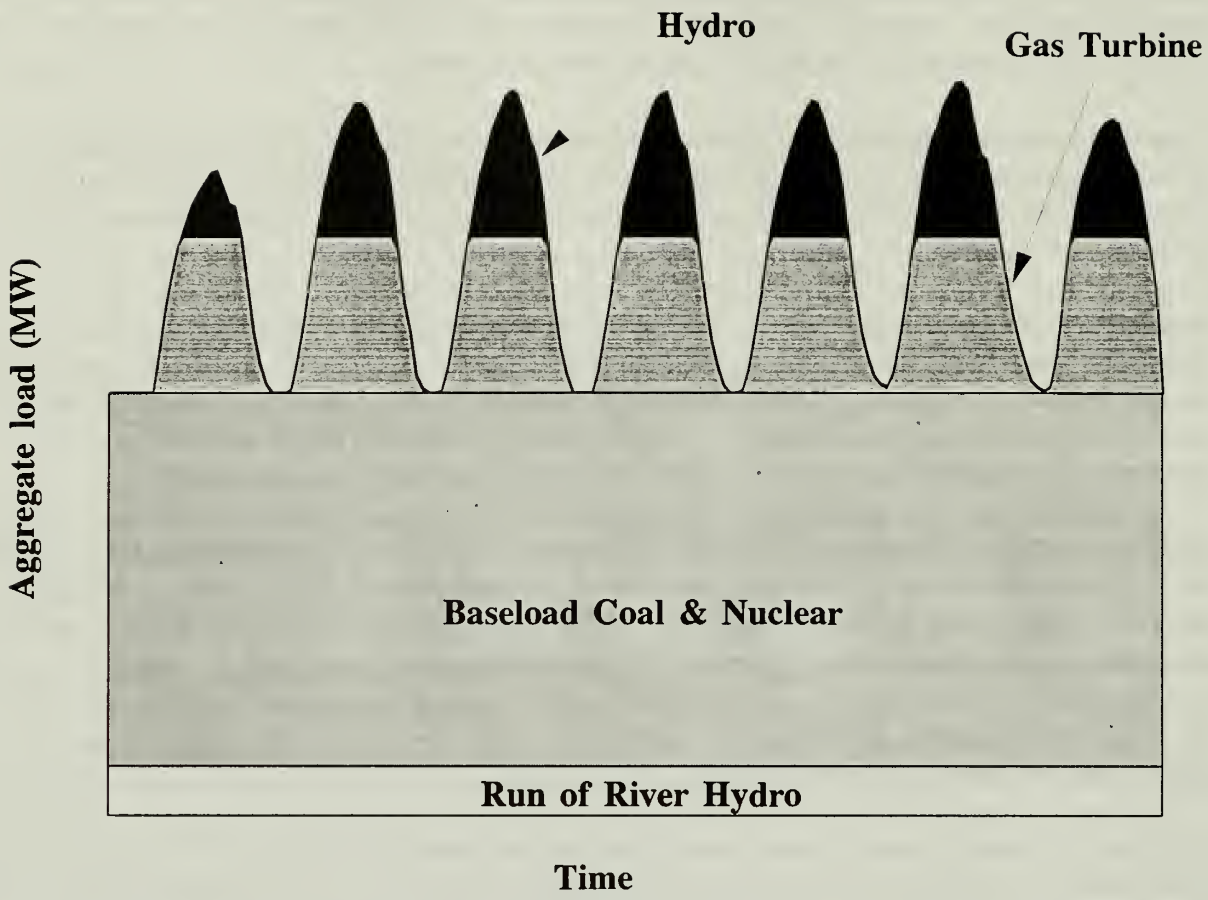


Figure 4. Idealized Use of Coal, Gas, and, Hydroelectric Power to Meet Load.

APPENDIX 3. ECONOMICS, FINANCE AND RELATED TOPICS

Economic versus financial impacts

Economists classify impacts which arise from a management action as economic impacts and financial impacts. Economic impacts are the dollar value of resources committed by the United States as a result of a proposed action. For energy analyses, this would include the use of fossil and nuclear fuels, the cost of any incremental capital expense necessitated by the action within the period of analysis, and the value of environmental and other nonmarket impacts, such as recreation. Explicitly omitted from all economic analyses is consideration of investments made prior to the period of analysis. These investments are called sunk costs.

Sunk costs are relevant to the short-term analyses undertaken with this model, since the price of power bought or sold on a contractual basis may contain both a fixed and a variable cost component. The fixed cost component is a prorated sunk cost. This component of the cost of power is excluded from the economic analysis through the use of spot market prices, which reflect only the variable cost of production.

In contrast, the focus of a financial analysis is to provide an estimate of the monetary impact to an identifiable sub-group or organization. Financial analyses typically include both resource (economic) and sunk costs. Estimates of financial impact frequently differ from estimates of economic impact because financial effects are calculated for only a sub-set of the affected population, they do not include the value of negative impacts on other economic sectors and groups, they do not incorporate environmental and nonmarket effects, and, because they do include sunk costs. In general, financial impacts may be less than, greater than, or equal to economic impacts.

Economic value

When the economic option is enabled (option=1), GCPS09 calculates the gross economic value of the electricity produced during the simulation. The accounting stance used is the United States as a whole. The economic value computed by this program is a measure of Net Economic Development (NED) benefits as defined in U.S. Water Resources Council (1983). For the economic analysis, all power is assumed to be sold on the spot market at spot market prices without regard to existing contractual obligations, if any. In this context, the spot market price is a measure of the short-run marginal cost of integrated system production subject to transmission limitations and other physical constraints.

The calculation of gross economic value (EV) is described in equation 6. Economic value is dependent on the spot market prices used (Appendix 9) and the hourly pattern of generation simulated by the model.

$$EV = \sum_{i=1}^{24} [generation_i * sprice_i] \tag{6}$$

where:

$generation_i$ = (total) simulated generation in hour i
$sprice_i$ = spot market price in hour i

Financial value

When the economic option is disabled (option=0), GCPS09 calculates and displays the gross financial value of the simulated generation. The accounting stance is that of Western Area Power Administration. Revenues from both firm and spot market sales are components of gross financial value. Again, gross financial value is purely a financial measure— it is not a measure of economic value.

The calculation of gross financial value (FV) is described by equation 7. Gross financial value, as calculated by this model is a measure of the estimated gross revenue for the simulated day. Gross financial value is dependent on the assumed SLCA/IP wholesale rate, spot market prices (Appendix 8), the price of dump energy (Appendix 6), the hourly pattern of generation simulated by the model, and the amount of this simulated generation which is assumed to be used to meet long-term firm load (Appendix 10).

$$FV = \sum_{i=1}^{24} [pprice_i * firmgen_i + sprice_i * spotgen_i + dprice * dumpgen_i] \tag{7}$$

where:

$firmgen_i$ = firm power generation in hour i
$spotgen_i$ = spot market generation in hour i
$dumpgen_i$ = dump power in hour i
$pprice_i$ = firm power price in hour i
$sprice_i$ = spot market price in hour i
dprice = dump energy price

Spot market component

When the economic option is disabled (option=0), the portion of the gross financial revenues contributed by sales in the spot market, if any, is calculated and displayed. The calculation is described by equation 8. Spot market revenue is the amount of revenue realized by selling generation in excess of firm power needs on the spot market at the assumed spot market prices shown in Appendix 8. The contribution of the spot market component to gross financial value

depends on the pattern of simulated generation, long-term firm power requirements, and the relative differences between the respective price vectors. In cases where substantial amounts of spot market power are produced and where spot market prices exceed firm power prices, spot market revenues may be a relatively large component of financial value.

$$SR = \sum_{i=1}^{24} [sprice_i * spotgen_i] \tag{8}$$

where:

$spotgen_i$ = spot market generation in hour i
$sprice_i$ = spot market price in hour i

When the economic option is enabled (option=1), all power produced is assumed to be sold on the spot market. Therefore, when this option is enabled, the spot market component is not displayed.

Dump energy component

When the economic option is disabled (option=0), the portion of the gross financial revenues contributed by dump energy sales, if any, is calculated and displayed. The calculation is described by equation 9. Dump revenue (DR) is the amount of revenue realized by selling generation in excess of aggregate load at the price for dump energy shown in Appendix 6. The contribution of dump energy to gross financial value depends on the pattern of simulated generation, the pattern of aggregate load, and the price of dump energy. In most cases, no dump energy is generated and no dump revenue is generated. When dump energy is generated, the financial revenue derived from it's sale is generally quite limited.

$$DR = \sum_{i=1}^{24} [dprice * dumpgen_i] \tag{9}$$

where:

$dumpgen_i$ = dump energy generation in hour i
dprice = dump energy price

When the economic option is enabled (option=1), all power produced is assumed to be sold on the spot market. Therefore when this option is enabled, the dump energy component is not displayed.

Limitations

The economic or financial value calculated for any given day may or may not be representative of other days during the month. Since load varies during the week and across the month, the pattern

of generation observed for any one day is unlikely to resemble other days during the month. In addition, the price of electricity during any given day may be less than, greater than, or equal to the price at other times during the month. As a result, the simulated results obtained for a single day cannot be extended to the remaining days during the month with any degree of confidence.

Both the financial and economic estimates calculated by this program are short-run estimates. In the short-run, all capital is fixed. In the long-run, changes in operations may result in the addition of new powerplants to serve load or may result in planned units being constructed earlier in time than otherwise would be the case. Both the financial and economic measures calculated by this model are based on short-run costs. Consequently, the value estimates derived from this program are not appropriate for estimating the long-run impacts of operational changes.

Intended use

The estimates of value calculated by GCPS09 are primarily useful as short-run indices of economic or financial impact when comparing alternative simulations. For example, the difference in gross financial value between one day simulated with an unlimited maximum daily change and one day simulated with an 8,000 cfs maximum daily change provides a useful index of financial impact. Clearly, these measures must be interpreted and used with due consideration of the limitations described.

APPENDIX 4. THE PEAKSHAVING MODEL.

Introduction

Given knowledge about the generation resources owned by competitors, the expected aggregate demand or load, the amount of water available for release, and the engineering limitations of their own plant, the problem faced by the profit maximizing hydropower producer is to generate power during the onpeak hours, when it is most valuable.

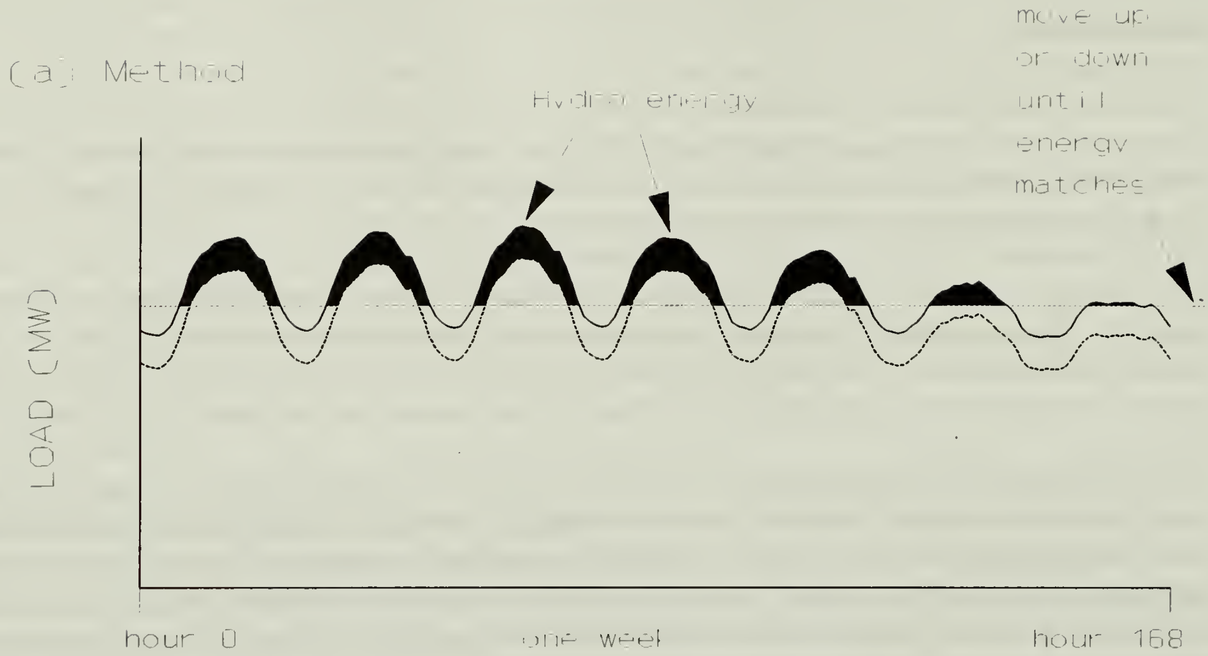
Peakshaving is one of two widely used approaches for simulating limited energy hydroelectric dispatch. The methodology has been extended by the Environmental Defense Fund to incorporate operational constraints. The general peakshaving model is a standalone module of EDF's Elfin model, a state-of-the-art electric resource planning and production cost model (EDF 1995).

The peakshaving model simulates the cost minimizing use of a hydroelectric resource given an hourly load curve and the volume of water available for release. The objective is to reduce the peaks in the aggregate demand curve by using hydropower to supply energy at periods when the demand is greatest. The remaining load is met by other generation facilities such as coal, nuclear, gas, and oil plants which are either more expensive to operate or respond to changes in demand more slowly.

The peakshaving model uses the hydroelectric resource most effectively within the constraints of the capacity and energy available. The existence of a storage reservoir means that there is operational flexibility with regard to the timing of water releases. However, this flexibility is limited by the amount of water available for release. In general, there is not enough water to support releases at a hydro unit's maximum capacity level throughout a month. Effective use of such a flexible, energy-limited resource means that the use of a hydroelectric facility should be maximized during peak periods and reduced during offpeak periods.

Graphical exposition

Operation of the peakshaving algorithm can be illustrated graphically using a one week chronological load curve. In this graphical treatment the effects of constraints are omitted for simplicity. We begin by drawing a second load curve below the original load curve. The distance between the original load curve and this second curve represents the capacity of the hydro resource (see Figure 5 (a)). Now, draw a horizontal line across the load curves. The area that is between the two load curves and above the horizontal line represents the energy potentially produced by the hydro resource (the shaded area in 5 (a)). In effect, the peakshaving algorithm moves the horizontal line up and down until the shaded area just matches the available hydro energy. Figure 5 (b) shows the resulting remaining load curve after peakshaving. At peak times, the maximum capacity of the hydro resource is used. During low load periods, no hydro power is used. Note that after peakshaving, the remaining load curve contains "flat spots."



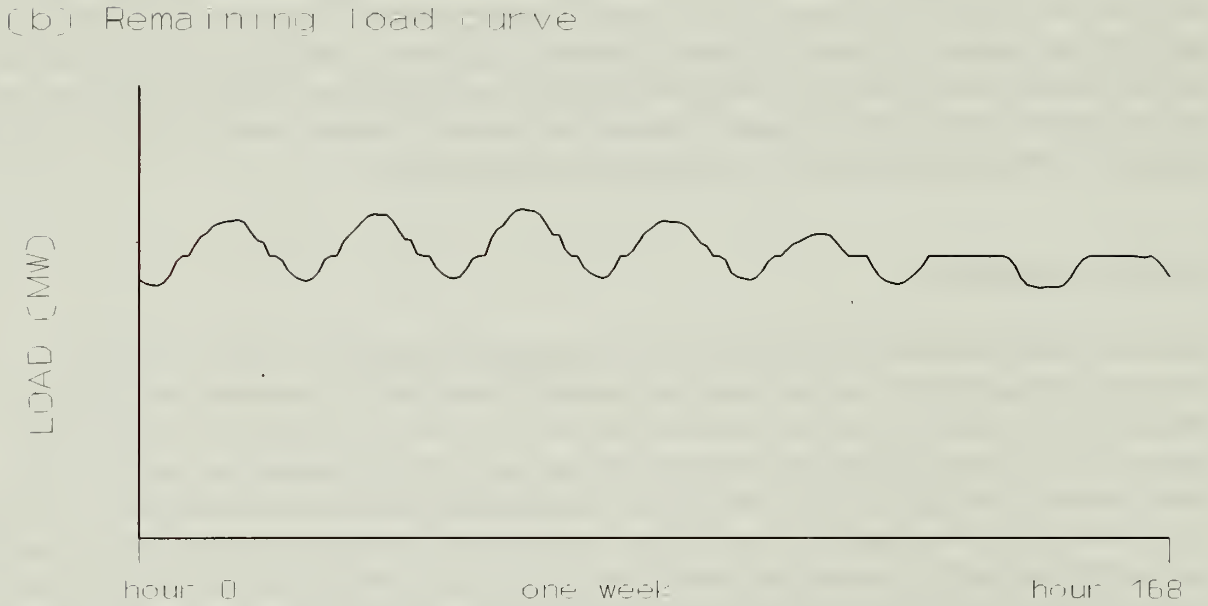


Figure 5. The Peakshaving Method and Remaining Load Curve.

Conceptually, the peakshaving algorithm proceeds as follows. The amount of hydro capacity and energy is calculated from the user supplied inputs. The hydro algorithm then uses an iterative procedure to find the megawatt level such that all energy is used and the remaining peak load is as low as possible. In other words, the algorithm finds the correct placement of the horizontal line in Figure 5 (a). For each hour, either (1) energy will be dispatched so that the remaining load is equal to the megawatt level of the horizontal line, or, (2) if the difference between the load curve and the megawatt level of the horizontal line is greater than the capacity, then the full capacity of the hydro resource will be dispatched at that hour.

An iterative binary search routine is used to obtain a solution. The routine begins by making a guess at the megawatt level for the horizontal line. It then checks to see if that level would require too much or too little energy compared to the amount of energy available. Based on the outcome of this comparison, a change in the megawatt level of the horizontal line is made and the energy is checked again. This search continues until the results are within a floating tolerance level of 1.0e-5 times the energy available.

Mathematical exposition

The peakshaving model can be formulated in a more formal mathematical sense. First, as with most real world applications, it is necessary to convert the natural units; flow rates, measures of volume, and energy, to a common metric in order to formulate the problem. To facilitate these conversions, two functions are employed. The first function, ef[], calculates the flow rate (cfs) required to produce a given amount of energy (mw) at a particular reservoir elevation. This relationship is obtained by solving the generation equation shown in Appendix 5 for flow. The second function, fv[], converts a flow rate (cfs) to a volume measure (af).

The goal of the profit maximizing hydropower producer is to identify the optimal pattern of hourly releases in cfs, $q_h(x)$, $\forall_h \in \{1,2,3,...H\}$. The function describing the optimal series of flows is shown in (10). Note that $q_h(x)$ is discontinuous and monotonically decreasing in x. In equation (10), expected aggregate load in hour (h) is L_h, the maximum generation release is c, and x is an arbitrary level of release.

$$q_h(x) = \left\{ \begin{array}{ll} 0, & \text{if } ef[L_h] \le x \\ ef[L_h] - x, & \text{if } x \le ef[L_h] \le x+c \\ c, & \text{if } ef[L_h] \ge x+c \end{array} \right\} \qquad \textbf{(10)}$$

To solve the peakshaving problem, find an x which satisfies equation (11), subject to the set of constraint equations (12-17):

$$\sum_{h=1}^{H} fv[q_h(x)] = mvol \tag{11}$$

st:

$$q_h(x) - q_{h+1}(x) \leq uprate \tag{12}$$

$$q_{h+1}(x) - q_h(x) \leq downrate \tag{13}$$

$$q_h(x) \leq c \tag{14}$$

$$q_h(x) \geq minf_h \tag{15}$$

$$\max(q_1(x) \ldots q_H(x)) - \min(q_1(x) \ldots q_H(x)) \leq mdc \tag{16}$$

$$c = \min(maxfc, potentialflow) \tag{17}$$

Where:

q_h = power release (cfs) at hour h.
L_h = expected aggregate load (mw) at hour h
maxfc = maximum flow constraint for the alternative (cfs).
$minf_h$ = minimum flow constraint in hour h for the alternative (cfs).
uprate = upramp rate (cfs).
downrate = downramp rate (cfs).
max() = maximum operator
min() = minimum operator
mdc = maximum daily change constraint for the alternative (cfs).
mvol = volume of water available for release during the month (af).
potential flow = the maximum flow which can physically be passed through the generators at a given lake elevation.

Example analysis

The peakshaving model is particularly valuable for analyzing the behavior of a hydroelectric plant with environmental constraints such as those studied extensively in the Operation of Glen Canyon Dam EIS (Reclamation 1995). For purposes of the Glen Canyon Dam EIS, ramp rates, maximum flows, minimum flows, and maximum daily changes in flow were constrained to varying degrees. The parameters which describe these constraints for each of the alternatives are detailed in

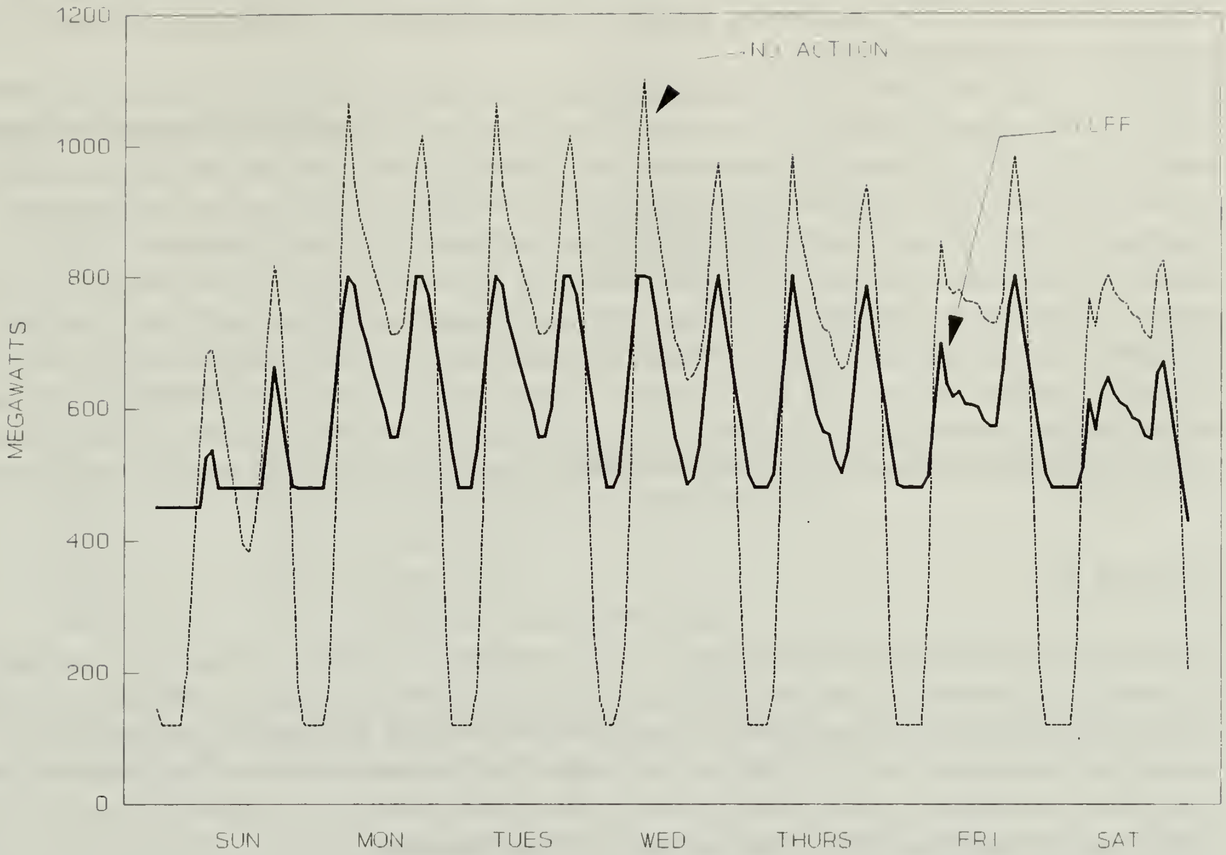


Figure 6. Simulated Generation for No Action and Interim Low Fluctuating Flow (iLFF) for a week in March 1996. Monthly volume = 850,000 af.

Appendix 13. Figure 6 compares the no action and Interim Low Fluctuating Flow alternatives as simulated by the peakshaving model. As shown in this Figure, constraints on power plant operations in the iLFF alternative greatly change the simulated pattern of hourly generation compared to no action.

Recent applications

The general peakshaving model was used to determine capacity for the HYDROLOGY analysis which is described in the Glen Canyon Environmental Studies Power Resources Committee Report (Power Resources Committee 1993) and the Glen Canyon Dam EIS. Another model, called the trapezoid model, was also used to determine capacity for the GCDEIS and the PRC reports. The results of that modeling effort were used to generate the contract rate of delivery (CROD) results described in the EIS.

A description of the trapezoid model is contained in Harpman (1995). A cursory comparison of the trapezoid model, the peakshaving model, and actual generation is found in Harpman, Rosekrans, and Moulton (1994).

There are a number of differences between this program and the more general peakshaving model used by EDF. The primary differences are that GCPS09 is specialized for simulating operations at Glen Canyon Dam, is capable of simulating only one day at a time, and has an integrated graphics display module. Analysis of a single 24 hour period has some limitations. First, aggregate load varies considerably during the days of the week and across the weeks during the month. Simulated results based on a single day's aggregate load may or may not reflect this variation in an appropriate manner. Second, the peakshaving model is capable of optimally allocating water across the days in the month to meet aggregate load. Use of a single day analysis period, as implemented in this version of the model, is overly restrictive. The results obtained using GCPS09 may or may not be similar to the results obtained when a monthly model is used.

Intended use

As explicitly stated in a number of places in this document, GCPS09 is primarily an educational tool and is not intended for use as a decision tool. For rigorous analyses of alternative operating criteria, the authors recommend that the monthly version of the peakshaving model or a production cost model, such as Elfin, be used. The Environmental Defense Fund loans or licenses the general peakshaving model and Elfin on a case by case basis. For further information, contact EDF at the address listed inside the front cover of this publication.

APPENDIX 5. FLOW, HEAD, AND GENERATION

Power generation at Glen Canyon Dam in megawatts (MW) is calculated from flow and head as shown in the equation below:

$$MW = \frac{\Gamma * eff * flow * head}{hptokw * 1000}$$

Where:

Γ =	62.40, The specific weight of water at 50 degrees fahrenheit (lbs/ft^3).
eff =	0.822992, efficiency factor (dimensionless).
head =	effective head (feet).
flow =	Water release (cfs).
hptokw =	737.5, Conversion factor (kw/ft-lbs).

This program uses the methods described in Reclamation (1988, sections 3.38.2-3.38.5 and 1987, sections 9.1-9.2) to calculate effective head.

The efficiency factor used here is calibrated to produce 1,288.2 MW at 33,200 cfs and a lake elevation of 3,700 feet (effective head = 557.22 ft).

APPENDIX 6. DEFAULT PARAMETERS

The default parameters shown below are supplied with version 1.0 of this program, dated 07/19/96. These parameters are located in the text file named GCPS09.P_1 and may be changed with a text editor. If changes are made to GCPS09.P_1, the original format of the file must be maintained.

```
filename = GCPS09.P_1
parameter file for GCPS09.PAS
=======================================================
*
31                      {number of days in month }
850000                  {release volume (af/month)}
2500                    {upramp rate (cfs/hr)}
1500                    {downramp rate (cfs/hr)}
20000                   {maximum flow constraint (cfs)}
8000                    {maximum daily change constraint (cfs)}
3700                    {reservoir elevation (ft above msl)}
gcps09.p_2              {name of default price file}
summerc.dld             {name of default load file}
0                       {economic option ON=1, OFF=0 }
8.00                    {dump energy price ($/MWhr) }
```

APPENDIX 7. EXAMPLE MONTHLY RELEASE VOLUMES

Table 7-1. Monthly Release Volumes for the Range of Anticipated Hydrologies in Water Year 1996 Without Test Flow

	Minimum Probable		Most Probable		Maximum Probable	
	Release Volume (TAF)	EOM Reservoir Elevation (Ft)	Release Volume (TAF)	EOM Reservoir Elevation (Ft)	Release Volume (TAF)	EOM Reservoir Elevation (Ft)
October	900	3688.4	899	3688.4	900	3685.4
November	900	3683.8	899	3683.7	900	3684.6
December	800	3681.7	950	3681.6	1,800	3681.7
January	800	3675.0	1,100	3677.7	1,800	3676.3
February	800	3678.7	950	3674.9	1,800	3671.5
March	600	3674.9	850	3673.2	1,800	3666.5
April	550	3675.0	825	3674.9	1,800	3667.9
May	550	368	850	3681.2	1,500	3676.7
Jun	700	3684.7	950	3690.5	1,200	3692.9
July	825	3683.9	1,075	3691.6	1,200	3697.4
August	825	3688.4	1,100	3688.4	1,500	3694.9
September	730	3675.0	871	3683.4	1,800	3692.7
Total	9,030		11,320		16,400	

APPENDIX 8. DEFAULT PRICE/MINFLOW FILE

```
filename = GCPS09.P_2
D_HARPMAN
07/19/96
PRICE & MINFLOW VECTORS FOR GCPS09.EXE

REMARK: default parameter file

         prime       spot     min
 EOH     price      price    flow
  hr  ($/mwhr)  ($/mwhr)    (cfs)
   *
   1     20.17      17.79    5000
   2     20.17      17.70    5000
   3     20.17      17.49    5000
   4     20.17      17.47    5000
   5     20.17      17.47    5000
   6     20.17      17.73    5000
   7     20.17      17.34    8000
   8     20.17      17.90    8000
   9     20.17      20.79    8000
  10     20.17      23.20    8000
  11     20.17      25.93    8000
  12     20.17      26.35    8000
  13     20.17      26.35    8000
  14     20.17      26.92    8000
  15     20.17      26.85    8000
  16     20.17      25.12    8000
  17     20.17      24.40    8000
  18     20.17      23.76    8000
  19     20.17      23.79    8000
  20     20.17      24.09    5000
  21     20.17      23.45    5000
  22     20.17      23.45    5000
  23     20.17      21.51    5000
  24     20.17      19.48    5000
```

APPENDIX 9. EXAMPLE PRICE VECTORS

TABLE 9-1. WEEKDAY SPOT MARKET PRICES BY MONTH IN 1998 DEFLATED TO 1996 (UNITS: $/MWhr)

hour	oct	nov	dec	jan	feb	mar	apr	may	jun	jul	aug	sep
1	17.17	20.28	18.63	16.48	16.81	19.90	17.57	15.56	16.93	17.90	17.79	16.08
2	16.42	20.28	17.89	16.45	16.45	19.77	17.49	15.38	16.35	17.22	17.70	15.49
3	16.28	19.58	17.46	16.45	16.44	19.64	17.18	15.00	15.83	17.10	17.49	15.21
4	16.28	19.94	17.90	16.48	16.48	19.68	17.36	14.82	15.64	16.95	17.47	15.20
5	16.73	20.28	18.56	17.20	17.00	20.02	17.75	15.46	16.13	17.16	17.47	15.74
6	18.98	20.61	19.90	18.38	18.31	21.45	17.85	15.87	16.36	17.76	17.73	16.91
7	18.86	20.92	19.61	20.26	19.70	20.90	18.05	15.66	16.47	17.83	17.34	17.01
8	19.24	21.25	20.21	22.82	20.52	21.15	18.37	16.67	17.68	19.52	17.90	18.02
9	19.60	21.31	20.91	21.24	19.64	21.47	19.31	17.69	20.79	22.68	20.79	19.48
10	19.36	21.31	20.96	20.08	18.40	22.92	19.06	17.74	24.07	25.86	23.20	19.72
11	21.18	21.07	19.68	20.07	17.75	22.59	19.85	18.00	25.75	25.89	25.93	20.30
12	21.68	21.07	19.38	18.17	17.41	21.76	19.53	18.14	26.49	25.89	26.35	21.85
13	22.67	20.67	18.58	17.50	17.30	21.05	19.51	18.17	26.75	25.89	26.35	23.42
14	23.04	20.06	18.22	16.82	17.09	20.40	19.51	18.72	26.56	25.89	26.92	21.25
15	23.32	19.35	17.74	16.34	16.69	20.34	19.97	19.16	27.38	25.89	26.85	23.90
16	23.32	19.55	17.74	16.15	16.57	20.27	19.96	19.25	27.10	25.89	25.12	23.82
17	23.16	20.60	19.40	17.06	16.97	20.44	20.05	18.99	26.55	25.89	24.40	23.83
18	23.28	21.11	20.67	20.38	17.79	21.63	19.96	18.41	25.89	25.89	23.76	23.77
19	24.39	21.50	21.50	20.38	19.20	23.72	19.75	17.94	25.89	25.89	23.79	22.87
20	24.14	21.31	21.36	20.37	19.20	24.72	20.24	17.85	26.40	25.89	24.09	22.48
21	22.40	21.19	21.03	19.83	18.34	23.28	19.52	17.86	25.76	25.89	23.45	20.35
22	20.48	21.07	20.29	17.70	18.33	20.60	19.36	17.48	25.20	25.89	23.45	19.70
23	19.95	21.07	20.34	18.72	18.59	21.82	18.44	16.51	23.15	22.94	21.51	19.02
24	18.94	20.39	19.51	16.90	17.64	20.15	17.55	15.70	18.70	21.34	19.48	17.49

These price vectors are contained in the file named SMM1996.PRN, which was supplied with this program.

APPENDIX 10. DEFAULT SUMMER LOAD FILE

```
filename = SUMMERc.DLD
D_HARPMAN
02/23/96
LOAD FILE FOR GCPS0?.EXE
UNITS: mw
REMARK: AGGREGATE LOAD CURVE (AUGUST 30, 1996)
REMARK: SLCA/IP FIRM POWER (AUGUST 30, 1996)

ndays = 1
              1    2    3    4    5    6    7    8    9   10   11   12
*
aggregate load
 830961    3085 2946 2860 2814 2824 2994 3228 3444 3679 3903 4127 4269
 830962    4362 4507 4594 4655 4680 4643 4527 4472 4404 4168 3790 3439
*
SLCA/IP firm power (70%)
 830961     449  438  434  431  431  440  462  474  534  585  629  711
 830962     753  774  788  795  792  790  774  762  754  704  565  463
```

APPENDIX 11. OPTIONAL WINTER LOAD FILE

```
filename = WINTERc.DLD
D_HARPMAN
03/19/96
LOAD FILE FOR GCPS0?.EXE
UNITS: mw
REMARK: AGGREGATE LOAD CURVE (JANUARY 24, 1996)
REMARK: SLCA/IP FIRM LOAD (JANUARY 24, 1996)

ndays = 1
           1    2    3    4    5    6    7    8    9   10   11   12
*
aggregate load
124961  2207 2191 2199 2248 2360 2675 3163 3376 3202 3044 2916 2782
124962  2696 2642 2597 2582 2598 2767 2977 2932 2878 2763 2543 2312
*
SLCA/IP firm load (70%)
124961   340  340  340  340  346  372  522  666  646  607  576  540
124962   512  499  485  490  510  644  741  725  685  581  436  356
```

APPENDIX 12. ALLOWABLE RANGE OF USER-SPECIFIED PARAMETERS

The table below illustrates the minimum and maximum allowable values for user-specified input parameters.

Table 12-1. Valid Parameter Ranges

PARAMETER	MINIMUM	MAXIMUM
monthly release volume (af)	1,000 (see note 1)	5,000,000 (see note 5)
number of days in month (days)	28	31
reservoir elevation (feet)	3,490 (see note 4)	3,708
upramp rate (cfs/hour)	500	33,200
downramp rate (cfs/hour)	500	33,200
maximum flow constraint (cfs)	(see note 2)	33,200
minimum flow constraint (cfs)	1000 (see note 1)	(see note 2)
maximum daily change (cfs/day)	0 (see note 3)	33,200
dump energy price ($/MWhr)	0	(see note 6)

Note 1. The user-specified monthly release volume must be sufficient to sustain the user-specified minimum flow constraint.

Note 2. The maximum flow constraint must be 2,000 cfs greater than the user-specified minimum flow constraint. The user-specified minimum flow constraint must be 2,000 cfs less than the user-specified maximum flow constraint.

Note 3. If the user specifies a maximum daily change of 0.0, a steady flow alternative is indicated.

Note 4. The minimum power pool is elevation 3,490 feet. Power cannot be generated at reservoir elevations below this level.

Note 5. Monthly release volumes may be constrained by lake elevations. For example, releases in excess of 48,200 cfs cannot be made if the lake elevation is below 3,648 feet.

Note 6. The price of dump energy is generally less than the spot market price.

APPENDIX 13. OPERATING LIMITS OF ALTERNATIVES ANALYZED IN GLEN CANYON DAM EIS

	Unrestricted Fluctuating Flows		Restricted Fluctuating Flows				Steady Flows		
	No Action	Maximum Powerplant Capacity	High	Moderate	Modified Low	Interim Low	Existing Monthly Volume	Seasonally Adjusted	Year-Round
[1] Minimum releases (cfs)	1,000 Labor Day-Easter [2]3,000 Easter-Labor Day	1,000 Labor Day-Easter [2]3,000 Easter-Labor Day	3,000 5,000 8,000 depending on monthly volume, firm load, and market conditions	5,000	8,000 between 7 a.m. and 7 p.m. 5,000 at night	8,000 between 7 a.m. and 7 p.m. 5,000 at night	8,000	[3]8,000 Oct-Nov 8,500 Dec 11,000 Jan-Mar 12,500 Apr 18,000 May-Jun 12,500 Jul 9,000 Aug-Sep	[4]Yearly volume prorated
[5] Maximum releases (cfs)	31,500	33,200	31,500	31,500 (may be exceeded during habitat maintenance flows)	25,000 (exceeded during habitat maintenance flows)	20,000	Monthly volumes prorated	18,000 (exceeded during habitat maintenance flows)	[4] Yearly volume prorated
Allowable daily flow fluctuations (cfs/24 hours)	30,500 Labor Day-Easter 28,500 Easter-Labor Day	32,200 Labor Day-Easter 30,200 Easter-Labor Day	15,000 to 22,000	±45% of mean flow for the month not to exceed ±6,000	[6]5,000 6,000 or 8,000	[6]5,000 6,000 or 8,000	[7]±1,000	[7]±1,000	[7]±1,000
Ramp rates (cfs/hour)	Unrestricted	Unrestricted	Unrestricted up 5,000 or 4,000 down	4,000 up 2,500 down	4,000 up 1,500 down	2,500 up 1,500 down	2,000 cfs/day between months	2,000 cfs/day between months	2,000 cfs/day between months
Common elements	None	None	Adaptive management (including long-term monitoring and research) Monitoring and protecting cultural resources Flood frequency reduction measures Beach/habitat-building flows New population of humpback chub Further study of selective withdrawal Emergency exception criteria						

[1] In high volume release months, the allowable daily change would require high minimum flows (cfs).
[2] Releases each weekday during recreation season (Easter to Labor Day) would average not less than 8,000 cfs for the period from 8 a.m. to midnight.
[3] Based on an 8.23-million-acre-foot (maf) year. In higher release years additional water would be added equally to each month, subject to an 18,000-cfs maximum.
[4] For an 8.23-maf year, steady flow would be about 11,400 cfs.
[5] Maximums represent normal or routine limits and may necessarily be exceeded during high water years.
[6] Daily fluctuations limit of 5,000 cfs for monthly release volumes less than 600,000 acre-feet; 6,000 cfs for monthly release volumes of 600,000 to 800,000 acre-feet; and 8,000 cfs for monthly volumes over 800,000 acre-feet.
[7] Adjustments would allow for small power system load changes.

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MISSION STATEMENTS

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally-owned public lands and natural resources. This includes fostering wise use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. Administration.

The mission of the Bureau of Reclamation is to manage, develop, and protect water and related resources in an environmentally and economically sound manner in the interest of the American public.